BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2020-263-E

Cherokee County Cogeneration Partners, LLC Complainant/Petitioner, v. Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Defendants/Respondents.	)	**POST-HEARING LEGAL BRIEF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLP ("DEP" and, together with DEC, the "Companies"), by and through counsel, hereby respectfully submit this Post-Hearing Legal Brief to the Public Service Commission of South Carolina ("Commission") pursuant to instructions from the Commission Chairman at the close of the July 30, 2021 hearing in this matter. The Companies' Legal Brief addresses the central legal issues raised in Cherokee County Cogeneration Partners, LLC's ("Cherokee" and, together with DEC and DEP, the "Parties") Complaint, and distills for the Commission the issues requiring adjudication to allow the parties to move forward with execution of a new power purchase agreement ("PPA") for the output of Cherokee's 98 megawatt ("MW") combined cycle cogeneration facility (the "Cherokee Facility" or the "Facility"), if Cherokee and its parent company, LS Power, elect to commit to a new contract term.

In short, the Companies believe that any new PPA between DEC and Cherokee: (i) should provide Cherokee non-discriminatory avoided cost rates and terms that are also just and reasonable to DEC's customers in compliance with the Public Utilities Regulatory

Policies Act of 1978 ("PURPA"); (ii) should apply the avoided cost methodology recently reviewed and approved by this Commission in Commission Order No. 2019-881(A); and (iii) should be based upon DEC's most current, accurate, and appropriate avoided cost rates calculated and circulated to Cherokee in February 2021. DEC and Cherokee are also in agreement that a 10-year dispatchable tolling agreement structure is appropriate based upon current regulatory circumstances.

The Companies provide the following legal brief to support their positions on these issues:

I. **Introduction**

In its Complaint and Request for Interim Relief filed on November 2, 2020, Cherokee renders serious allegations that DEC and DEP "refus[ed] to negotiate in good faith" to reach a new PPA with Cherokee and, in doing so, violated their obligations under PURPA and the South Carolina Energy Freedom Act ("Act 62"). Compl. at pp. 1-3. Cherokee alleges that the Companies failed to timely provide Cherokee with their avoided cost rates,[1] failed to provide supporting information,[2] failed to provide non-discriminatory terms and conditions recognizing Cherokee's dispatchability,[3] and acted in a discriminatory manner that violated Cherokee's rights to sell power under PURPA.[4]

[1] *Id.* at 3 (alleging that the Companies "delay[ed] for several months the timeline between discussions with Cherokee and the making of an offer").

[2] *Id.* (alleging that the Companies "fail[ed] to provide supporting information that would enable Cherokee to confirm whether their offers reflect avoided costs").

[3] *Id.* at 3, 14-15 (alleging that the Companies ("fail[ed] to offer terms and conditions for a PPA which reflect Duke's avoided costs and are not discriminatory to Cherokee").

[4] *Id.* at 5 (alleging that "Cherokee has the right to enter into a PPA, and Duke has failed and refused to enter into such an agreement on reasonable, statutorily required terms.").

In stark contrast to these bold allegations, the substantial testimony and evidence in this case demonstrates that Cherokee's bad faith allegations are misguided and unsupported hyperbole. Indeed, both DEC and DEP followed a standardized, non-discriminatory process to offer PPA rates to Cherokee that reflected each utility's then-current avoided costs as of the date(s) that Cherokee notified DEC (and later DEP) of its intent to sell power. In addition, both utilities timely responded to Cherokee's requests for supporting information, and both utilities offered Cherokee avoided cost rates and terms fully consistent with the rates and terms offered to all other large qualifying facilities ("QF") at the time. Faced with this evidence, Cherokee appears to make the paradoxical argument that DEC and DEP did not act in good faith *precisely because* they treated Cherokee like all other QFs greater than 2 MW in size and not eligible for the standard offer ("Large QFs") offering to sell power under PURPA.

Ultimately, LS Power rejected each of the five updated avoided cost rate offers made to Cherokee over the two-and-a-half-year period between Cherokee's initial request in September 2018 and February 2021. The facts and evidence of record also show that during this period Cherokee, not DEC or DEP, affirmatively caused several months-long periods of delay in the negotiation process through its inaction, in addition to waiting more than two years before bringing these allegedly serious claims of discrimination and purported bad faith dealings to the Commission.

Notwithstanding the Companies' good faith attempts to reach a new PPA agreement with Cherokee, the disputed legal issues in this proceeding requiring Commission adjudication are limited. The Companies and Cherokee have already agreed to structure the PPA as a dispatchable tolling agreement subject to a 10-year term, so neither the form nor term of contract are issues that require a Commission ruling. At the heart of the Parties' continued dispute is whether Cherokee ever established a legally enforceable obligation ("LEO") to sell power to either DEC or DEP over a future term and, regardless of the LEO date, whether DEC and DEP utilized an appropriate methodology to calculate avoided capacity costs over the forecasted term of contract.

Cherokee asserts that it established a LEO with DEC through its initial communications in September 2018. However, Cherokee's actions—including notifying DEC of its intent to sell its *full capacity and energy* output first to DEC under PURPA in September 2018, followed by its non-competitive bid into DEP's non-PURPA 2018 capacity solicitation weeks later, followed by another purported LEO to sell its *full capacity and energy* output to DEP under PURPA in December 2018—demonstrate that Cherokee, in fact, *did not* legally obligate itself to sell capacity and energy to either DEC or DEP at the utility's avoided cost, as Cherokee's conduct demonstrated that it could walk away at any time and offer its power to another utility. Similarly, Cherokee's contention that it is entitled to payment for full capacity costs in each contract year even though DEC did not have an immediate need for additional undesignated capacity to serve its customers is inconsistent with guidance from the Federal Energy Regulatory Commission ("FERC") and this Commission's precedent as there would be no "avoided" capacity cost, and the Companies' customers would be forced to pay for unnecessary capacity prior to the first year of capacity need designated in DEC's integrated resource plan ("IRP").

In sum, to enable the parties to move forward toward execution of a new PPA, the Commission must determine:

1. Whether Cherokee's actions in the fall of 2018 warrant the Commission establishing a non-contractual LEO based on a finding that LS Power legally obligated Cherokee to sell its power to DEC in September 2018;

2. Whether DEC's and DEP's application of the standardized peaker methodology appropriately recognized each utility's first year of capacity need and reasonably calculated avoided cost rates offered to Cherokee; and

3. To the extent Cherokee alternatively intends to sell output to DEP, whether Cherokee met its obligation under PURPA to obtain transmission service from DEC to deliver its power to DEP in order to be paid DEP's avoided costs.

Answers to all three of these questions are clear from both the evidence and applicable law. Specifically, Cherokee did not make a legally enforceable obligation committing to sell its power to either DEC in September 2018 or to DEP at any time prior to filing the Complaint in this matter. The evidence shows that DEC and DEP followed the standardized peaker methodology approved by the Commission in Order No. 2019-881(A) to calculate avoided capacity and energy costs offered to Cherokee. Utilizing this methodology, DEC and later DEP offered avoided cost rates and PPA terms that were fully consistent with the rates and PPA terms being offered to all other Large QFs. However, Cherokee repeatedly rejected and did not agree to prospective PPA rates based upon DEC's or DEP's actual avoided costs. Finally, even Cherokee does not dispute that it never arranged for or otherwise requested transmission service from DEC to deliver its energy from the DEC network to DEP.

The potential impact to customers of the Commission's decision is significant as highlighted by testimony from the Office of Regulatory Staff ("ORS") Witness Dawn Hipp. Since the Companies' customers ultimately pay the avoided costs that DEC and DEP pay to QFs like Cherokee through the fuel clause, it is important that avoided cost rates are not stale and inaccurate and that the date on which a LEO is recognized is reasonably aligned with the date on which customers begin receiving (and paying for) the QF's power. Cherokee's position that the Commission should deviate from the standardized peaker methodology recently reviewed and approved in Order No. 2019-881(A) in order to compensate Cherokee for capacity value before the utility's next undesignated IRP need arises would result in rates that are substantially higher than DEC's actual avoided costs—a subsidy that would be passed on to DEC's customers. For these reasons and as set forth in greater detail below, the Companies believe that the rates DEC offered to Cherokee in February 2021 are the most accurate and appropriate for a future PPA between DEC and Cherokee.

II. Factual Background

DEC has been purchasing Cherokee's power under PURPA for 22 years. DEC first contracted to purchase energy and capacity from the Cherokee Facility in 1994, when it executed a 15-year non-dispatchable PPA with Cherokee that was structured as a conventional "must-take" PURPA agreement (the "1994 PPA"). (Tr. Vol. 2, pp. 242.7-8.) By Amendment, the term of the 1994 PPA began on November 2, 1998, when the Facility first commenced commercial operations. The successor PPA between the two Companies was executed on June 28, 2012, for a 7.5-year term set to terminate on December 31, 2020, as approved by the Commission in Order No. 2012-743 (the "2012 PPA"). (*Id.*) Unlike the 1994 PPA, the 2012 PPA was structured as a dispatchable tolling agreement whereby DEC was responsible for providing fuel to the Cherokee Facility and dispatching the Facility as needed. (*Id.*)

DEC and Cherokee initiated discussions for a successor to the 2012 PPA in late summer of 2018, more than two years before the 2012 PPA was set to expire. (Tr. Vol. 2, p. 242.9.) The ensuing interactions between DEC, DEP, and Cherokee are memorialized in the Timeline of Communications and the 21 supporting documents, which were marked as Hearing Exhibits 12 and 13, respectively. In short, those communications as well as the testimony of DEC/DEP Witness Michael Keen and Cherokee Witness Nathan Hanson demonstrate that Cherokee purported to make a legally binding offer to sell the *full* output of the Cherokee Facility to DEC and later to DEP on at least three different occasions, reversing course each time as to which utility should be obligated to purchase its power. Cherokee was also dilatory in requesting information to support the Companies' rate calculations, waiting nearly six months from receiving DEC's rates in October 2018 to make an initial request for such information and nearly nine months after receiving the Companies' response to take any additional action. (Hrg. Ex. 12.) On just two occasions, Cherokee purported to engage in "negotiations" by delivering an unsolicited term sheet offering to enter into PPAs at rates far *above* DEC's and DEP's avoided costs. (*Id.*)

In contrast to Cherokee's delays and excessive avoided cost calculations, the undisputed evidence shows that DEC and DEP followed a standard, non-discriminatory process to provide Cherokee with indicative avoided cost rates, calculated each time as of the date of Cherokee's request, along with draft PPAs. (*Id.*) The Companies also timely responded to each of Cherokee's requests for supporting information in a standardized manner consistent with their treatment of other Large QFs. (*Id.*) During this period of intermittent negotiations with Cherokee, the Companies were also engaged in multiple contested avoided cost proceedings in Docket Nos. 1995-1192-E (to update DEC's and DEP's standard offer rates) and then 2019-185-E and 2019-186-E (to implement Act 62). Cherokee did not intervene in these proceedings, where the Commission approved the same peaker methodology to calculate avoided capacity and energy costs that DEC and DEP used to calculate rates for Cherokee.[5]

From 2018 to present, DEC and/or DEP provided their avoided costs to Cherokee on five occasions. The Companies' first three offers (made in December 2018, February 2019, and April 2019) were based upon the same terms and conditions offered to all other Large QFs at the time. Cherokee rejected or let each of those offers expire. Although Cherokee did make two counter-offers to DEC in December 2018 and DEP in April 2020, DEC and DEP timely responded that these offers exceeded the Companies' actual avoided costs. (*Id.*)

III. Argument

A. Cherokee's Conduct in September 2018 Did Not Establish a LEO Committing to Sell Power to DEC Over a Specific Future Term

On September 17, 2018, Cherokee sent a letter to DEC attaching its FERC Form 556 and a modified version of the Notice of Commitment Form then used for small QFs less than 5 MW in North Carolina, stating that it was "making a legally binding offer of all capacity and energy associated with the Facility *to DEC* as of January 1, 2021" under PURPA. (Hrg. Ex. 13, at 12 (Timeline Attachment 2) (emphasis added).) DEC responded by letter on October 5, 2018, stating that Cherokee's written notice of its intent to sell power for a new contract term did not establish a mutually-binding legally enforceable obligation, but that DEC, as required by PURPA, would "commence negotiations with Cherokee" and "deliver its avoided costs as well as a form PPA that DEC would agree to execute in order to establish a legally binding arrangement to purchase Cherokee's full

[5] Order No. 2019-881(A), at 58.

output of energy and capacity over a five-year term commencing on January 1, 2021." (Hrg. Ex. 13, at 17 (Timeline Attachment 3).) On October 31, 2018, DEC provided its avoided cost rates "calculated using DEC's standard system [peaker] methodology for [QFs] based on DEC's September 2018 system costs" and standardized form of PPA that DEC would execute if Cherokee committed to proceed with the transaction. (Hrg. Ex. 13, at 21 (Timeline Attachment 4).) After limited communications between DEC and LS Power representatives, including Cherokee presenting an unsolicited term sheet, on December 12, 2018, Cherokee sent similar communications purporting to "mak[e] a legally binding offer of all capacity and energy associated with the Facility *to DEP* as of January 1, 2021" under PURPA. (Hrg. Ex. 13, at 27 (Timeline Attachment 6) (emphasis added).) On December 21, 2018, DEP provided Cherokee a written response committing to commence negotiation and to provide its avoided cost rates and a form PPA. (Hrg. Ex. 13, at 36 (Timeline Attachment 7).) On that same day, DEC also provided an emailed response to Cherokee's term sheet and limited efforts to commence negotiation, explaining that the offered rates exceed DEC's avoided costs and that Cherokee's recent communications to DEP effectively superseded its prior notice of intent to sell to DEC:

> Aaron,
>
> Thanks for sending me this term sheet. As I mentioned on the phone, DEC is not actively pursuing any capacity at this time because DEC does not currently have a capacity need. In addition, the pricing included in this term sheet is well above DEC's avoided costs we sent you on 10/31/18 and is also higher than the current market price for capacity delivered into DEC. Furthermore, as you are aware, Cherokee sent DEP a legally binding offer committing to sell all the capacity and energy from Cherokee to DEP commencing on 1/1/21. This commitment will super cede other offers from Cherokee. At this time, we are developing the avoided costs for DEP which you requested. Please let me know if you have any questions. Thank you.

(Hrg. Ex. 13, at 39 (Timeline Attachment 8).)

As the facts show and as further described herein, Cherokee did not establish a binding and enforceable commitment to sell its power to DEC simply by mailing a letter and inapplicable Notice of Commitment Form, and Cherokee's subsequent conduct further demonstrates that it did not make a legally binding commitment to DEC.

1. A QF Must Make a Legally Enforceable Commitment to Sell Power to Establish a Non-Contractual LEO in the Absence of a PPA

There is no dispute that DEC and DEP are each electric utilities under Section 210 of PURPA that are each individually obligated to purchase power from QFs at the utility's avoided cost.[6] 16 U.S.C. § 824a-3(a)(2); 18 C.F.R. 292.101(b)(2), (6). FERC's regulations establish the framework for setting avoided cost rates under PURPA and provide QFs the option to sell energy to the utility on either an "as available" basis or to commit sell capacity and energy pursuant to a "legally enforceable obligation" at a forecasted avoided cost rate. 18 C.F.R. § 292.304(d). Where a QF exercises its right to enter into a legally enforceable obligation to "deliver energy and capacity to a utility over a specified term[,]" the utility is obligated to purchase the QF's power at the utility's avoided costs fixed either at the time the obligation is incurred (prior to the delivery term) or at the time of delivery. 18 C.F.R. § 292.304(d)(1)(A)-(B).

Ultimately, a legally enforceable obligation is a *mutually-binding* contractual commitment in the form of a PPA obligating the QF to sell and deliver power over a future delivery term and obligating the utility to purchase that power at avoided cost rates. Recognizing that at the time PURPA was enacted in 1978, utilities historically had been unwilling to offer to purchase power from new non-utility QF generators, FERC included the legally enforceable obligation concept in its regulations to protect a QF's right to sell

[6] As explained by DEC/DEP Witness Bowman, DEC and DEP are separate "electric utilities" under PURPA operating separate power systems with separate and distinct transmission systems and separate avoided costs. Accordingly, they are each independently obligated to implement PURPA and to purchase QF power at their respective avoided cost rates. (Bowman Pre-Filed Direct, pp. 16, 31.)

its output and "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility *merely by refusing to enter into a contract with the qualifying facility*." Order No. 69, 45 Fed. Reg. at 12,224 (emphasis added).

FERC has also made clear that "the establishment of a legally enforceable obligation turns on the QF's commitment, and *not* the utility's actions" such as requiring a utility-executed contract, or requiring a QF to tender an executed interconnection agreement which must first be provided by the utility. *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at PP 22-24 (Dec. 15, 2016) (emphasis in original). FERC has explained:

> [A] QF has the option to commit itself to sell all or part of its electric output to an electric utility . . . Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations."

JD Wind 1, LLC, 129 FERC ¶ 61,148, at P 25 (2009), *reh'g denied,* 130 FERC ¶ 61,127 (2010). In this way, the non-contractual LEO concept is designed as an added protection to the QF's right to sell power to the utility, as the QF and the utility can either negotiate and agree to a PPA or, where the utility refuses to enter into a mutually-binding contract, the QF can *demonstrate through its conduct* that it has committed itself to sell to an electric utility. The QF's conduct can essentially commit the utility to purchase power from the QF by establishing a non-contractual, but still binding, legally enforceable obligation.

In evaluating whether a non-contractual LEO has arisen in the absence of a mutually-binding contractual commitment in the form of a PPA, it is the responsibility of the State Commission overseeing a regulated utility's PURPA implementation to assess the QFs conduct—*i.e.,* whether the QF obligated itself to sell and deliver power to the utility at the utility's avoided cost—and the utility's conduct—*i.e.,* whether the utility acted unreasonably and refused to enter into a PPA to purchase the QF's power at the utility's avoided costs, as required by PURPA. Order No. 688-A, 119 FERC 61,305 at P 139 (2007) ("[I]n the division of responsibilities of administering PURPA between [FERC] and state regulatory authorities (and non-regulated utilities), it is the state regulatory authorities (or non-regulated utilities) that determine whether and when a legally enforceable obligation is created, and the procedures for obtaining approval of such an obligation."); *see also Power Res. Grp., Inc. v. Pub. Util. Comm'n*, 422 F.3d 231, 239 (5th Cir. 2005).

In Order No. 872, FERC reemphasized that a LEO must create a meaningful and binding obligation on the QF that "allows utilities to reasonably rely on the LEO in planning for system resource adequacy." Order No. 872 at P 684, 687; 18 C.F.R. § 292.304(d)(3). Order No. 872 recognizes that requiring a QF to make a binding "legally enforceable obligation" actually committing to sell its power to the utility is integral to a utility's ability to conduct accurate long-term resource planning. As DEC/DEP Witness Glen Snider explained, a QF that is no longer contractually bound to sell power to a utility is free to make any number of business decisions without liability or accountability to the previously-purchasing utility—including electing to sell energy "as available" under PURPA, selling to another buyer in the wholesale market, or simply choosing to discontinue operation of the facility. (Tr. Vol. 2, at p. 390.10.) Accordingly, from a resource planning perspective, the utility cannot rely upon the QF to deliver capacity and energy over a future term to reliably serve customers unless and until the QF legally commits itself to do so.

Considering the type of binding commitment necessary to establish a legally enforceable obligation, this Commission has found that no LEO was created when the QF was, among other things, "free to walk away from the negotiations without liability." *Pacolet River Power Co., Inc. v. Duke Power Co.*, Order on Remand Dismissing and Denying Complaint, Dkt. No. 95-1202-E, Order No. 2001-663 (Jul. 24, 2001) ("because Pacolet was free to walk away from the negotiations without liability, . . . no 'legally enforceable obligation' was created").[7] In *Pacolet*, the QF argued that its letter to the utility requesting a long-term contract under PURPA at rates available as of the date of the letter constituted a legally enforceable obligation. *Id.* at 4. Like Cherokee, the QF was already operational and had an active PPA with the utility at the time it purported to create a new LEO by letter. In finding the QF's letter "did not and could not create a 'legally enforceable obligation[,]'" the Commission emphasized the lack of any legal consequence to the QF if it chose to "walk away" from its purported commitment—just as Cherokee recognized no obligation to DEC and suffered no consequence when it offered to sell its full output to DEP on both a non-PURPA and PURPA basis after making the same offer to DEC.

Other jurisdictions have likewise recognized that QFs must make a meaningful and binding commitment to establish a LEO. For example, the Commonwealth Court of Pennsylvania has found that a LEO arises "where the qualifying facility has *agreed to obligate itself* to deliver at a future date energy and capacity to the electric utility" and "ensure[s] the certainty of rates for purchases from a qualifying facility which *enters into a commitment* to deliver energy or capacity to a utility." *Armco Advanced Materials Corp.*

[7] Unlike Cherokee, Pacolet's existing contract with Duke Power was not set to expire in the near term. Instead, Pacolet sought to establish a new LEO *before* termination of the existing PPA to avail itself of higher avoided cost rates. While the Commission noted this unusual procedural posture in its decision, it was just one of the factors weighing against establishment of a LEO, and there is nothing in the decision to indicate that it was a controlling factor. *Pacolet*, Order No. 2001-663, at 12.

v. Pa. Pub. Util. Comm'n, 135 Pa. Commw. 15, 33-34, 579 A.2d 1337, 1347 (1990) (emphasis added).[8] As the Pennsylvania Court explained:

> Where a QF has entered into a contract with a utility, the QF has a legally enforceable obligation to deliver power. ***Where a QF has done everything within its power to create such an obligation***, either by tendering a contract to the utility or by petitioning the PUC to approve a contract or to compel a purchase, ***and only an act of acceptance by the utility or an act of approval by the PUC remains to establish the existence of a "contract",*** then the "legally enforceable obligation" contemplated by § 292.304(d)(2) has been created, and the QF is entitled to rates based on avoided costs calculated from the date of the QF's action.
>
> However, the "legally enforceable obligation" we have just described does not exist at a time during "serious negotiations" between the parties (whether at the time of agreement in principle on price or otherwise) when the ***QF has not yet obligated itself to deliver power and remains free to walk away from the negotiations without liability***.

Id. (emphasis added.). Importantly, the Pennsylvania Court found that no LEO existed even when the parties had agreed in principal on the rates *and* were engaging in serious negotiations for a PPA. The Utah Public Service Commission similarly recognized in 2016 that a non-contractual LEO arises in the absence of a mutually-binding PPA where "the utility acted in a manner inconsistent with the standard customs and practices attendant to the negotiation and execution of QF PPAs and that 'but for' such actions the parties would have entered a contract." *In the Matter of the Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Thayn Hydro, L.L.C.*, Docket No. 16-035-04, 2016 WL 4126153, at *7 (Utah P.S.C. July 29, 2016).[9]

[8] A copy of the *Armco* case is attached to this Legal Brief as Supplemental Authority 1.

[9] A copy of the *Rocky Mountain Power* case is attached to this Legal Brief as Supplemental Authority 2.

Based on this guidance, the Commission should scrutinize Cherokee's conduct in purportedly committing to sell its output and DEC's conduct in offering to purchase Cherokee's output at its avoided cost rates under PURPA to determine whether Cherokee unilaterally established a non-contractual LEO.

2. Cherokee Did Not Make a Legally Enforceable Commitment to Sell Power to Either DEC or DEP in Fall 2018

Cherokee's attempts to establish LEOs with DEC and DEP in the fall of 2018 were unsuccessful for a variety of reasons.

***Cherokee attempted to sell its full capacity and energy output to multiple utilities*.** First, like the Complainant in *Pacolet*, Cherokee's conduct demonstrates that it was free to, and in fact did, "walk away" from its purported commitment to DEC without consequence, and then effectively rejected DEC's avoided cost rates. More specifically, just six days after mailing its letter to DEC, Cherokee offered to sell all of its output to DEP pursuant to DEP's non-PURPA 2018 capacity solicitation. (Hrg. Ex. 12, at 1.) Reversing course a second time, Cherokee purported to make a second "legally binding offer of all capacity and energy associated with the Facility" to DEP under PURPA in December 2018. (Hrg. Ex. 13, at 27-29 (Timeline Attachment 6).) As Witness Kendal Bowman explains, Cherokee has also recently argued to FERC that upon expiration of the 2012 PPA, Cherokee "indisputably" would have the right to, and is contemplating, the option of selling its output to third parties. *See Cherokee County Cogeneration Partners, LLC, Request for Rehearing*, Docket No. ER21-304-002, at 11-12 (May 3, 2021) ("[u]pon expiration of the PPA, Cherokee will indisputably 'ha[ve] the right to sell to a third party,' and, in obtaining and maintaining its market-based rate authorization, Cherokee has provided . . . 'manifestation of [Cherokee]'s "plan to sell" output to third parties' after the termination of the PPA[.]"). Indeed, in rejecting Cherokee's request for rehearing regarding FERC jurisdiction over Cherokee's interconnection to DEC, FERC itself noted Cherokee's arguments that the expiry of the 2012 PPA along with "the fact that Cherokee has obtained and retained market-based rate authority" to make non-PURPA sales "collectively demonstrate a 'manifestation of a plan to sell' output to third parties[.]" *Cherokee County* 176 FERC ¶ 61,069 at P 7 (2021).[10]

A QF cannot make a legally binding commitment to sell *all* of its capacity and energy to more than one utility at the same time. Accordingly, and because DEC and DEP are separately regulated entities and separate electric utilities under PURPA, Cherokee's actions of shifting between "legally enforceable offers" to the two utilities underscores that these purported commitments were non-binding and unenforceable as neither DEC nor DEP had any legally enforceable rights to the Cherokee Facility's output and could not count on output from the Cherokee Facility in their respective resource planning to serve customers after the 2012 PPA expired. Accepting a non-contractual LEO as being formed in these circumstance would be inconsistent with FERC's (and this Commission's) expectation that a QF must actually commit itself to sell to an electric utility to form a LEO and would be contrary to the express goals in Order No. 872.

***Cherokee's initial actions of sending a non-binding letter and modifying an otherwise inapplicable Notice of Commitment Form did not create a legally enforceable obligation*.** Also like the Complainant in *Pacolet*, Cherokee's actions of sending a letter and inapplicable Notice of Commitment Form to either or both of the Companies did not

[10] A copy of FERC's decision in the *Cherokee County* case is attached to this legal brief as Supplemental Authority 3.

create a legally enforceable obligation. Attachment of the Notice of Commitment Forms to Cherokee's letters did not lend any additional credibility to Cherokee's "commitment." The forms were intended for use by North Carolina QFs less than 5 MW in size attempting to sell output to DEC or DEP in North Carolina. Cherokee made significant modifications to this otherwise inappropriate form, to accommodate Cherokee's 98 MW facility and adjusting the jurisdiction from North Carolina to South Carolina.

Under any interpretation of these facts, Cherokee's actions served only to commence negotiations by making a "legally enforceable *offer*"—not obligation—as stated in Cherokee's letter. However, this offer was not binding on Cherokee, and Cherokee's act of filling out a doctored, unapproved Notice of Commitment Form did not create a LEO or bind Cherokee to sell to DEC in any way. As recognized by DEC's October 5, 2018 response letter, Cherokee's written notice of its intent to sell power for a new contract term was the first step in "commenc[ing] negotiations[.]" (Hrg. Ex. 13, at 17 (Timeline Attachment 3).) DEC took the second step by "deliver[ing] its avoided costs as well as a form PPA that DEC would agree to execute in order to establish a legally binding arrangement to purchase Cherokee's full output of energy and capacity over a five-year term commencing on January 1, 2021." (*Id.*) Cherokee then failed to progress those negotiations and "to [do] everything within its power to create such an obligation" with DEC, as recognized by the Pennsylvania Court in *Armco.* DEC's communications demonstrate that the utility acted in a reasonable and consistent manner adhering to the same standardized process used in the negotiation and execution of QF PPAs with all other QFs, while Cherokee refused to enter into a contract at DEC's offered avoided costs.

Cherokee's purported Notice of Commitment did not extend indefinitely. Importantly, the actual terms of the modified Notice of Commitment Form Cherokee submitted did not purport to preserve Cherokee's right to sell its output in perpetuity. As Witness Glen Snider explained during the hearing, the Notice of Commitment Form approved for use in North Carolina does not create an open-ended right to the utility's avoided cost without further action by the QF to memorialize its initial commitment through timely execution of a PPA. Section 6 of the Notice of Commitment Form delivered by Cherokee provided that avoided cost rates under the Notice of Commitment Form would expire 30 days after the utility delivered an executable PPA to the QF if the QF failed to contractually obligate itself to sell and deliver power over a future term. As Witness Snider explained, this reasonable limit on the time in which a QF can execute a PPA to contractually memorialize its Notice of Commitment Form also aligned with the standardized process DEC followed with Cherokee in the fall of 2018, allowing the parties 60 days from the date of delivery of avoided cost rates and executable form of PPA to finalize any negotiations or the avoided cost rates would become stale and expire. (Tr. Vol. 2, pp. 390.11, 390.31-32.)

Cherokee never accepted DEC's or DEP's avoided costs. As additional evidence of its lack of serious commitment to DEC or DEP, Cherokee never accepted either Company's calculated avoided cost rates. By rejecting each of the Companies' five offers of avoided cost rates and PPAs and making counter offers at rates well above the Companies' avoided costs, (*see* Hrg. Ex. 13, at 9 (Attachment 8) ("the pricing included in this term sheet is well above DEC's avoided costs.")), Cherokee's claim of a LEO is inconsistent with FERC's regulations and PURPA. While DEC and DEP followed the

Companies' standardized process for negotiating and finalizing PPAs with Large QFs, Cherokee did not actively pursue meaningful discussions with DEC or later DEP to execute a new PPA.

<u>Cherokee delayed negotiations and never intervened in the Companies' avoided cost proceedings</u>. While Cherokee repeatedly alleges that the Companies delayed the negotiation process, the undisputed evidence confirms that Cherokee did not diligently pursue a successor PPA. Cherokee waited six months from the date it first received DEC's rates to ask for any information supporting those rates, (Hrg. Ex. 13, at 50-51 (Attachment 12)), and nearly nine months from receiving the Companies' response to take any further action toward a successor PPA. (Tr. Vol. 2, pp. 332-333) ("[W]e got [Cherokee's] request [for information] in May of that year, and we responded in June. And then I didn't hear from them for almost ten months after that. . . . During that next nine, ten months . . . , there was no additional conversation at all and definitely nothing on requesting additional information.").) These delays by Cherokee show that it did not diligently pursue a new PPA with DEC or DEP after each utility had provided its avoided cost rates and form of PPA to Cherokee for review and execution.

In addition, although claiming to have suffered hardship because the Companies "refused" to provide sufficient data supporting their rate calculations, Cherokee failed to ever follow up to question the Companies' use of the peaker methodology to calculate avoided cost rates and failed to take timely action to seek Commission review of the methodology. Cherokee did not intervene in either the Companies' 2019 or 2021 avoided cost proceedings to challenge the appropriate approach for calculation of avoided cost rates. Since the Commission is tasked under Act 62 with approving the Companies' avoided cost methodology in biennial avoided cost proceedings, that clearly would have been the appropriate forum for Cherokee to propose an alternate methodology or to seek a reversal of the Commission's position on capacity payments in the absence of a forecasted IRP capacity need. Rather than proactively pursuing any of these options that would have provided for timely resolution between the parties, Cherokee instead did nothing to advance its position and, instead, made unsolicited counter-offers asking the Companies to pay Cherokee based upon rates that were not calculated consistently with the Commission-approved peaker methodology.

<u>Cherokee filed its Complaint more than two years after it purports to have established a LEO</u>. Cherokee's lack of intent to bind itself into an actual commitment is apparent from the fact that Cherokee failed to take any regulatory action until November 2020—more than 2 years after asserting a LEO to DEC in September 2018. Cherokee never engaged with ORS to attempt to resolve its concerns, nor did it file the Complaint during a time period that might reasonably lead to a resolution in advance of the December 31, 2020 termination of the 2012 PPA. Instead, Cherokee waited until the eleventh hour—over two years after Cherokee asserts it established a LEO with DEC—to file its Complaint and seek relief from the Commission.

<u>Cherokee has failed to present any credible evidence that DEC "refused to negotiate" towards a successor PPA.</u> In contrast to Cherokee's false narrative that DEC and DEP failed to negotiate a successor PPA in good faith in the fall of 2018, the facts and correspondence between the parties demonstrate that DEC followed a standardized methodology and process to calculate avoided cost rates using the peaker methodology and to then deliver those rates and a form PPA that DEC was prepared to execute if Cherokee desired to contractually obligate itself to a new contract. DEC's October 31, 2018 letter also provided Cherokee sixty (60) days to finalize negotiations of the PPA. Cherokee has not offered any evidence that DEC was discriminatory and treated Cherokee differently than all other QFs in the fall of 2018. Cherokee has not offered any evidence that DEC refused to provide an executable PPA or that DEC was unwilling to enter into commercially reasonable negotiations regarding its terms. Instead, the facts and correspondence show that it was Cherokee that was unwilling to commit to sell its power at DEC's avoided costs and, instead of engaging in negotiations with DEC, Cherokee began looking for a better PURPA deal to sell its power to DEP in December 2018.

For all of these reasons, Cherokee did not, and could not have, established a LEO in the Fall of 2018.

B. Avoided Cost Rates Must Reflect the Utility's Actual Avoided Costs and be Calculated Pursuant to Commission-Approved Methodology

In addition to demanding DEC recognize a September 2018 LEO in the absence of any meaningful, binding commitment to sell its output to DEC at the time, Cherokee also argues that DEC should pay it rates that are well above DEC's actual avoided capacity and energy costs based upon a methodology that deviates from the one approved by this Commission. The uncontroverted evidence in this case demonstrates that DEC treated Cherokee the same as all other Large QFs in terms of methodology used to calculate avoided capacity and energy rates and the 5-year term of contract offered in fall 2018. Accordingly, in assessing Cherokee's claim, the Commission must determine whether DEC should either use the Commission-approved peaker methodology to calculate avoided cost rates or adopt the rates calculated by Cherokee's expert, Mr. Strunk, which would treat

Cherokee more favorably than all other similarly-situated Large QFs at the time they notify the utility of their intent to sell.

1. *The Companies' Avoided Cost Calculation Methodology*

As extensively discussed in the 2019 avoided cost proceedings, DEC and DEP apply the "peaker methodology" to forecast the Companies' avoided cost of capacity and energy and to calculate the avoided cost rates paid to QFs. The peaker methodology is a widely-used approach to quantifying a utility's forecasted avoided capacity and energy costs, and this Commission has consistently approved the Companies' use of the peaker methodology to set its avoided cost rates. (Tr. Vol. 2, at 390.17-18.) Specifically, in 2019, the Commission found that the peaker methodology is "a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs." Order No. 2019-881(A), at 29.

The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs. (Tr. Vol. 2, pp. 390.17.) As Witness Snider explains, this approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. (Tr. Vol. 2, pp. 390.18.) Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. (*Id.*)

Importantly, the Companies use the peaker methodology to calculate rates for PPAs structured both as must-take agreements and dispatchable tolling agreements, relying on the most current inputs and assumptions of avoided capacity and energy needs at the time a QF offers to sell. (Tr. Vol. 2, pp. 338.8-9.) As Cherokee's expert, Mr. Strunk, conceded, the value of the utility's avoided cost calculated using the peaker methodology does not change when avoided costs are paid under a dispatchable tolling structure versus a must-take agreement. (Tr. Vol. 1, pp. 201-02.)

2. *Avoided Cost Rates Must Accurately Reflect Future Capacity Need*

Under PURPA, QFs must be fairly and reasonably compensated for the incremental capacity and energy costs that, *but for* capacity and energy provided by the QF, the utility would be forced to generate or purchase elsewhere to serve its customers. 16 U.S.C. § 824a-3(d) (defining incremental cost of alternative energy under PURPA). In other words, PURPA was not intended to force a utility (and its customers) to pay for capacity that it does not otherwise need. *See Order No. 872* at P 171 discussed *infra*.

In this case, Cherokee contends that DEC offered avoided cost rates that were discriminatory because they did not ascribe an immediate undesignated need for capacity value to be paid for the Cherokee Facility's capacity in each year of the contract. However, at the time Cherokee submitted its September 2018 communication to DEC, DEC's first avoidable capacity need as identified in its 2018 IRP was projected to arise in 2028.[11] Accordingly, the forecasted five-year term avoided cost rates that DEC provided to Cherokee in October 2018 appropriately did not include any capacity payment to Cherokee

[11] *See* Duke Energy Carolinas, LLC 2018 Integrated Resource Plan at 55, Docket No. 2018-10-E (filed Aug. 31, 2018) ("DEC 2018 IRP").

over the five-year term of the proposed contract. For comparison, DEC's most recent 2020 IRP projected a first year of capacity need in 2026, and the rates DEC provided to Cherokee in September 2020 and February 2021 calculated avoided cost rates forecasted over a 10-year contract term and included a levelized payment for five years of avoided capacity (2026-2031) based on the Companies' 2020 projections of the cost of a CT or peaker unit. Despite DEC's consistent application of the peaker methodology in 2018 and 2020 and clear evidence that DEC had no undesignated avoidable capacity need until at least 2026, Cherokee maintains that it should receive immediate compensation for capacity value throughout the term of the contract. Cherokee's position is contrary to the intent of PURPA, as recently recognized by FERC in Order No. 872, and also contrary to both this Commission's and the North Carolina Utilities Commission's ("NC Commission") approval of the peaker methodology that the Companies use to calculate avoided cost rates for all other QFs.

In Order No. 872, FERC reiterated its longstanding precedent that "the Commission cannot require that prices charged by a QF exceed the purchasing electric utility's avoided cost, *if a purchasing electric utility has no need for additional capacity . . . the purchasing utility's avoided cost for capacity would be zero*." Order No. 872 at P 171 (*citing* 168 FERC ¶ 61,184 at P 33 n.58 and *Ketchikan*, 94 FERC ¶ 61,293) (emphasis added).

This Commission has also recognized the first year of capacity need principle well before DEC calculated its avoided costs to Cherokee in October 2018. As early as 1985, the Commission approved a zero-capacity credit for South Carolina Electric & Gas on the grounds that the utility lacked a capacity need and would therefore not avoid any capacity costs. *In Re: Small Power Production and Cogeneration Facilities—Implementation of*

Section 210 of the Public Utility Regulatory Policies Act of 19, Order No. 85-347, Docket No. 80-251-E (Aug. 2, 1985) ("The Commission, after considering all the relevant facts, believes that at this time, the capacity credit for SCE&G should be zero."). Reaching the same conclusion in spring 2018, months before DEC calculated avoided cost rates for Cherokee, the Commission again found a zero capacity cost to be "reasonable and appropriate" where such capacity was not needed and to ensure that the utility's customers would not "have[ ] to pay for excessive avoided capacity costs." *In re: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company*, Order No. 2018-322(A), Docket No. 2018-2-E (May 2, 2018) ("The Commission finds that SCE&G's proposal to set avoided capacity costs for its PR-1 and PR-2 rates at zero is reasonable at this time[.]").

Finally, and most importantly, this Commission's Order No, 2019-881(A) in the 2019 avoided cost proceeding clearly and unambiguously approved the Companies' approach to calculating avoided capacity costs. Following a detailed review of the Companies' avoided cost calculation methodology—which was informed both by extensive ORS and intervenor testimony as well as a detailed report by the Commission's independent third-party consultant, Power Advisory—the Commission approved the peaker methodology's calculation of avoided capacity costs based on the first year of capacity need projected in the current IRP and then levelizing that capacity value over the contract term. Order No. 2019-881(A), at 83, 89. In so holding, the Commission underscored that "customers should not be required to pay . . . QFs for capacity prior to the first year in which it is needed to serve system load[.]" *Id.* at 92.

Consistent with the Commission's detailed findings approving the peaker methodology and levelization of avoided capacity value of in Order No. 2019-881(A), the NCUC has also found this methodological approach appropriate and fully consistent with PURPA. In October 2017, approximately one year before DEC offered its avoided cost rates and terms to Cherokee, the NCUC held that "when calculating avoided capacity rates using the peaker methodology, it is appropriate to require a payment for capacity in years of a utility's integrated resource planning (IRP) forecast period when a capacity need is demonstrated during that period." *See Order Establishing Standard Rates*, N.C.U.C. Docket No. E-100, Sub 148 at 6-7, (Oct. 11, 2017) ("2017 Sub 148 Order"). The NCUC further held that inclusion of zero capacity value in avoided capacity rates until the utility's IRP shows a need is appropriate and not discriminatory as "PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need." *Id.* at 48-49.

Contrary to this significant precedent, Cherokee's retained expert, Mr. Strunk, argued that the Commission rejected the concept of a zero capacity payment in Order No. 2016-349. That Order, however, did not contain any discussion of zero capacity payments or any other substantive issue. Instead, the Commission summarily approved a stipulated revision to the Companies' standard offer tariff available only to small standard offer QFs 2 MW or less that adopted rates previously approved by the NCUC in 2015—in the proceeding *before* that, the NCUC approved the concept of a zero capacity payment in the 2017 Sub 148 Order discussed above. The barebones, procedural nature of Order No. 2016-349 does not supersede the Commission's earlier PURPA-implementation orders approving zero capacity credits and, most significantly, the Commission's detailed review and approval of DEC's and DEP's application of the peaker methodology in Order No. 2019-881(A).[12]

3. *The Companies' Avoided Cost Rates Provided to Cherokee from 2018 to Present were Developed Using Commission-Approved Methodology and Are Consistent with Act 62 and FERC Guidance*

DEC and DEP calculated avoided cost rates for Cherokee on five combined occasions—in October 2018 (DEC), January 2019 (DEP), June 2020 (DEP), September 2020 (DEC), and February 2021 (DEC). The first three sets of rates provided to Cherokee (October 2018, January 2019, and June 2020) were structured as five-year term must-take agreements, while the final two (September 2020 and February 2021) were structured as 10-year term dispatchable tolling agreements.[13] Each time, DEC and DEP calculated the avoided cost rates provided to Cherokee using the Commission-approved peaker methodology and standard inputs that were current as of the dates Cherokee requested in order to provide current, accurate, and appropriate rates that reflected the Companies' actual respective avoided costs at the time of calculation.[14] Moreover, each of the rates

[12] Witness Strunk also argued that DEC could avoid planned capacity additions such as construction of the Lincoln CT and uprates to the Bad Creek pumped hydro storage facility by purchasing already existing capacity from the Cherokee Facility. In fact, as Witness Snider explains, none of the planned capacity was avoidable. The Lincoln CT received a certificate of public convenience and necessity from the NCUC in 2017, rendering it an unavoidable cost in September 2018. Similarly, the planned uprates to the Bad Creek facility are being completed as part of the Companies' normal maintenance and, as such, are not costs that can be avoided once funded and underway. (Tr. Vol. 2, p. 390.28.). DEC and DEP followed the methodology approved by this Commission in Order No. 2019-881(A) as well as the methodology approved by the NCUC in its 2017 Sub 148 Order and Cherokee has not explained why DEC or DEP should have deviated from this methodology or treated Cherokee more favorably than any other QFs.

[13] In 2018, the Companies' standard practice was to offer 5-year must-take PPAs to all Large QFs. 10-year term PPAs were only available to QF projects up to 2 MW in size that were eligible for the Standard Offer. Act 62, which became law in May 2019, required utilities to offer 10-year PPAs to certain small power producer Large QFs above 2 MW in size. While Act 62 does not require the Companies to offer 10-year PPAs to large cogeneration QFs like Cherokee, DEC offered Cherokee this longer term in September 2020 and February 2021 in an attempt to compromise and reach a resolution that would allow the parties to move forward with a new QF PPA for the Cherokee Facility.

[14] Pursuant to Order No. 2020-315(A), the Companies now update inputs on a quarterly basis, and those inputs are available publicly through the Companies' Large QF Tariff. Prior to Order No. 2020-315(A), the

included levelized capacity payments (if any) calculated based on the first year of capacity need projected in the utility's most current IRP or IRP update as of the date of calculation and consistent with Order No. 2019-881(A).[15]

By following the Commission-approved methodology, the Companies treated Cherokee the same as any other Large QF seeking to enter into a non-standard offer PPA. In addition, because both the calculation methodology, inputs, and first year of capacity need are fixed separate and apart from the Companies' relationship with any one QF, calculation of the Companies' avoided costs is a fixed process and not subject to "negotiation" with Cherokee or any other QF.

4. <u>ORS Supports Using Commission-Approved Methodology</u>

Like the Companies, ORS supports using the Commission-approved methodology to calculate the Companies' respective avoided costs. (Hipp Pre-Filed Direct, at 5.) ("ORS recommends the successor PPA for Cherokee reflect avoided energy and avoided capacity rates calculated based on the methodology approved by the Commission."). ORS Witness Dawn Hipp noted that DEC's customers are currently paying Cherokee "significantly more" than DEC's actual avoided costs. (*Id.*) Accordingly, she underscored that "[f]rom the perspective of the customer, the 'ceiling' for energy and capacity payments to a QF is one that is based on [DEC's] actual avoided costs." (*Id.*)

Companies updated their respective inputs on a monthly basis and provided them to QFs upon request. (Tr. Vol. 2, at p. 390.19.)

[15] DEC's October 2018 rates reflected a first year of need in 2028 based upon the 2018 DEC IRP; DEP's February 2019 and June 2020 rates reflected a first year of need in 2020 based upon the 2018 DEP IRP; and DEC's September 2020 and February 2021 rates reflected a 2026 first year of need based upon the 2020 DEC IRP. (Tr. Vol. 2, at p. 338.5.)

5. *Witness Strunk's Avoided Cost Rate Calculation Does Not Accurately Reflect the Companies' Avoided Capacity Costs as of September 2018 and Would Result in Higher Avoided Cost Rates Than Paid to Any Other Large QFs*

As explained by DEC/DEP Witness John Freund at the hearing in this matter, Cherokee Witness Strunk's avoided cost rate calculation contains several obvious flaws. First, as Witness Strunk himself acknowledged, his calculation was intended to be an "order of magnitude" approximation rather than an accurate and precise calculation of DEC's avoided cost rates. (Tr. Vol. 1, p. 126.16.) More importantly, however, Witness Strunk used stale information from the standard offer rates approved in 2016—more than two years before Cherokee approached DEC about a new contract and more than four years before the 2012 PPA was scheduled to expire—and disregarded DEC's first year of capacity need identified in its then-current 2018 IRP when calculating DEC's projected avoided cost rates.

Witness Strunk's alternative avoided capacity cost calculation resulted in rates that are significantly above DEC's 2018 avoided costs. In particular, Witness Strunk explained that the capacity rate he calculated of $110/kWy under a dispatchable tolling agreement translates to approximately $47/MWh for both capacity and energy under a traditional must-take agreement. (Tr. Vol. 1, pp. 201-02.) This $47/MWh rate is well above the actual total (capacity and energy) avoided cost rates for DEC and DEP since at least 2018 as calculated by the Public Staff – North Carolina Utilities Commission and presented in Figure 2 of DEC/DEP Witness Snider's testimony. (Tr. Vol. 3, pp. 390.33 (Snider Direct Figure 2).)

Snider Direct Figure 2:[16]

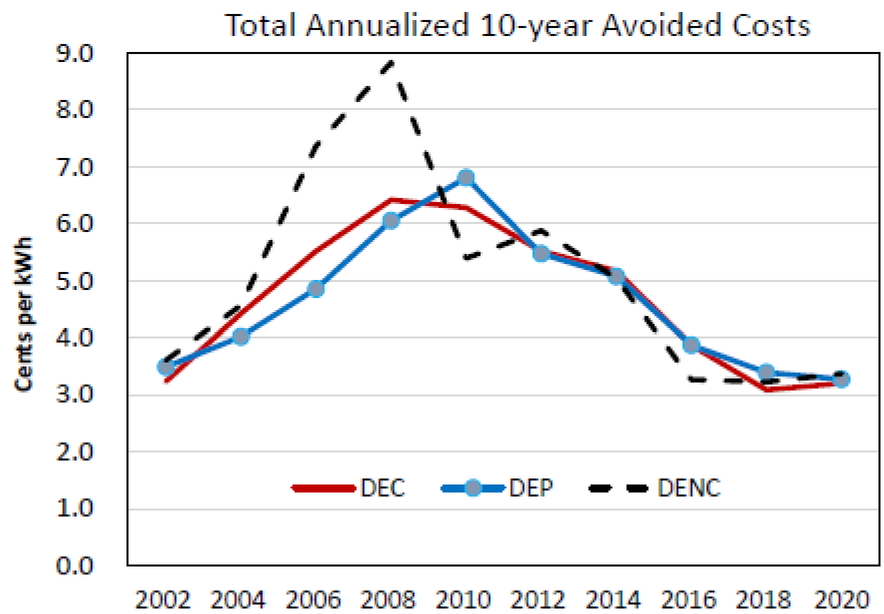

Figure 1: Total Annualized 10-year Avoided Costs (Approved and Proposed)

Accordingly, Witness Strunk's avoided capacity cost calculations are demonstrably higher than DEC's avoided cost at any point since negotiations commenced and cannot be implemented without overcharging customers at unjust and unreasonable rates and treating Cherokee more favorably than any other Large QF.

6. *DEC's Application of the Peaker Methodology and Commission-Approved Approach to Forecasting Avoidable Capacity Need are Not Discriminatory*

In addition to recommending avoided cost rates that significantly exceed the rates available to other Large QFs in 2018, Cherokee argues that DEC's avoided cost rate calculation was discriminatory because the utility did not use the avoided capacity value in

[16] Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020, Initial Statement of the Public Staff – North Carolina Utilities Commission at 8, Docket No. E-100, Sub 167 (Jan. 25, 2021) (showing approved total avoided costs for DEC, DEP, and Dominion Energy North Carolina from 2002-2018 and proposed annualized avoided cost rates for 2020).

DEC's still-available Schedule PP Standard Offer Tariff. However, Cherokee's reliance on pricing available under the Standard Offer approved over two years earlier by Order No. 2016-349 is both self-serving and misplaced. Under Act 62, the Companies' Standard Offer is available only to small QFs that are less than or equal to 2 MW in size. By contrast, the Cherokee Facility is a very large 98 MW cogeneration QF, meaning that it exceeds the size limit for Standard Offer eligibility by nearly 50 times and also exceeds the 80 MW limit applicable to small power producer QFs. Indeed, in the 2019 avoided cost proceeding, this Commission underscored the critical importance of ensuring appropriate quantification of avoided cost rates for large QFs separate and apart from Standard Offer rates, instructing that "[t]o accurately quantify DEC's and DEP's avoided costs for Large QFs not eligible for the Standard Offer, it is appropriate for DEC and DEP to . . . incorporate the most up-to-date inputs under the approved peaker methodology[.]" Order No. 2019-881(A), at 30. Simply put, Cherokee's argument that it was discriminatory for DEC to refuse to offer it the exceedingly old and stale avoided capacity value in DEC's Standard Offer Tariff is a misguided and thinly-veiled attempt to be paid rates that significantly exceeded DEC's calculation of avoided costs in fall 2018 and continue to significantly exceed DEC's avoided costs today.

7. *DEC's Rates Calculated in February 2021 are the Most Accurate and Appropriate Avoided Cost Rates to Pay Cherokee Under a Future Contract*

Although each vintage of avoided cost rates provided by DEC and DEP were consistently developed using the peaker methodology and were accurate and appropriate as of the date they were calculated, the Companies believe that the February 2021 rates are the most accurate and appropriate rates for use in the successor PPA because they reflect DEC's actual avoided cost close in time to expiry of the original 2012 PPA. In particular, DEC's February 2021 rates were calculated using the Commission-approved peaker methodology and based on the same input used in the Large QF Tariff update effective in October 2020. Per Cherokee's request, the February 2021 rates were also structured as a dispatchable tolling agreement with a 10-year term.

C. To the Extent Cherokee Plans to Exercise its Right to Sell Output to DEP instead of DEC, Cherokee Must Obtain Transmission Service to Deliver Power and Sell to DEP

From December 2018 through at least the summer of 2020, Cherokee appeared to discontinue negotiations with DEC and, instead, notified DEP of its intent to sell its output to DEP. Cherokee took these initial steps even though the Cherokee Facility is located in and interconnected to the DEC system and not to the DEP system. This shift in Cherokee's plans to sell its power from DEC to DEP was due to DEP's significantly earlier capacity need in 2020, which DEP satisfied through the 2018 non-PURPA capacity solicitation, in which Cherokee participated but was not competitive. (Tr. Vol. 2., p. 242.12 (noting that Cherokee's bid to DEP's non-PURPA capacity solicitation "was the highest of any bid submitted and almost three times higher than the best bid offered"), 287 (noting that DEP "ended up executing five contracts [for] 1800 megawatts. . . . And Cherokee had a great opportunity to compete, but just like with the avoided cost, the market price . . . was just too low for them.").)

While the Companies recognize that PURPA provides QFs with the right to sell its output to any electric utility obligated to purchase the QF's output under PURPA, (Bowman Pre-Filed Direct, pp. 31-32), it is the QFs responsibility to arrange transmission service to transport its energy from the generating facility to the non-interconnected utility. 18. C.F.R. 292.303(d); *Kootenai Elec. Coop. Inc.*, 143 FERC ¶ 61,232 at PP 1, 33 (2013)(explaining that "[a] utility is obligated under PURPA . . . to purchase the output of a QF, even a QF located in another state, as long as the QF can deliver its power to the utility" and the "QF has the discretion to choose to sell to a more distant utility . . . as long as the QF can deliver its power to the utility[.]").

Under both PURPA and the Companies' FERC-jurisdictional Open Access Transmission Tariff ("OATT"), Cherokee has the right to request DEC to transmit and deliver Cherokee's capacity and energy to DEP or another utility, and DEC is obligated to provide this transmission service on a non-discriminatory basis under the Companies' OATT. However, Cherokee never took the necessary steps to request or otherwise arrange for transmission service from DEC to transport its energy from the Cherokee Facility to the DEP grid. To the extent a transmission-related dispute exists, those issues are subject to FERC's jurisdiction—and FERC has,in fact, confirmed that "Cherokee has offered no evidence that it has requested transmission service to transmit its power over DEC's transmission system to deliver to third parties." *Order Addressing Arguments Raised on Rehearing*, 176 FERC ¶ 61,069 at P 12 (2021).

In any event, it is not clear to the Companies that Cherokee still wishes to sell output to DEP—particularly since DEP has now filled its near-term capacity need and the applicable transmission service charges mean that it will not be able to obtain a more favorable rate—so this issue is likely moot. However, if Cherokee elects to exercise its rights under PURPA to sell to DEP, then DEC is prepared to provide non-discriminatory transmission service under the OATT and DEP is prepared to provide updated avoided cost rates to Cherokee.

IV. <u>Conclusion</u>

The overwhelming evidence in this case demonstrates that DEC and DEP at all times acted in good faith to execute a successor PPA with Cherokee and, in doing so, treated Cherokee no differently than any other Large QF. As they are required to do under PURPA, DEC and DEP each provided Cherokee with rates that reflected their actual avoided costs, calculated pursuant to the Commission-approved peaker methodology, using up-to-date inputs, and recognizing the utility's first year of capacity need presented in each utility's most current IRP. With respect to the three legal issues the Commission must adjudicate to allow the parties to move forward with a new PPA, the law is clear:

1. As a matter of law, Cherokee did not establish a legally enforceable obligation with DEC in September 2018. Indeed, Cherokee's attempts to sell the *very same* capacity and energy to multiple different utilities (including DEC, DEP, and a representation to FERC of its intent to sell to third parties in the wholesale power market) undermine one of the most fundamental LEO principles: that the commitment must create a meaningful and binding obligation committing the QF to deliver its capacity and energy to the utility in the absence of a PPA.

2. As a matter of law, DEC's and DEP's application of the peaker methodology using up-to-date inputs and applicable first year of capacity need resulted in rates that were reasonably calculated, non-discriminatory, and reflective of the Companies' respective avoided cost rates. The Commission should re-affirm the methodology approved in Order No. 2019-881(A) as applicable for Cherokee.

3. Cherokee has the right to sell its power to DEP as a non-interconnected utility at DEP's avoided cost under PURPA, but, to do so, Cherokee must arrange for FERC-jurisdictional transmission service from DEC to deliver its power to DEP. Because it is undisputed that Cherokee never requested transmission service from DEC to deliver its power, Cherokee has not met its obligation under PURPA.

As presented in this legal brief, the Companies believe DEC's rates provided to Cherokee in February 2021, which were calculated using inputs consistent with DEC's publicly available November 2020 update to its Large QF Tariff, are the most accurate and appropriate rates to pay Cherokee under a future 10-year non-dispatchable tolling agreement. The February 2021 rates offered to Cherokee best ensure that DEC's customers are not paying stale and excessive avoided cost rates for the output of the Cherokee Facility and that rates are appropriately calculated to compensate Cherokee for capacity and energy that is avoidable over the favorable-to-Cherokee dispatchable tolling agreement structure and 10-year term of PPA.

For these reasons and for all of the reasons set forth herein, the Companies respectfully request that the Commission find that: (1) Cherokee did not establish a LEO in September 2018; (2) the rates paid to Cherokee under any future contract should be calculated using the Commission-approved avoided cost methodology, including application of the peaker methodology, use of up-to-date inputs, and levelization of capacity payments based on the first year of need principle, as approved in Order No. 2019-881(A); and (3) to the extent Cherokee alternatively intends to sell its output to DEP, that Cherokee has not met its obligation under PURPA to obtain transmissions service and to deliver its power to DEP.

Respectfully submitted this, the 13th day of August, 2021

Heather Shirley Smith
Deputy General Counsel
Duke Energy Carolinas, LLC
Duke Energy Progress, LLC
40 W. Broad Street, Suite 690
Greenville, South Carolina 29601
Phone: (864) 370-5045
Email: heather.smith@duke-emergy.com

and

s/Frank R. Ellerbe, III
Frank R. Ellerbe, III (SC Bar No. 01866)
ROBINSON, GRAY, STEPP & LAFFITTE, LLC
1310 Gadsden Street
Columbia, South Carolina 29201
Phone: (803) 231-7829
Email: fellerbe@robinsongray.com

E. Brett Breitschwerdt
Tracy S. DeMarco
MCGUIREWOODS LLP
501 Fayetteville Street, Suite 500
PO Box 27507 (27611)
Raleigh, North Carolina 27601
(919) 755-6563
Email: bbreitschwerdt@mcguirewoods.com
Email: tdemarco@mcguirewoods.com

Attorneys for *Duke Energy Carolinas, LLC*
and *Duke Energy Progress, LLC*